

DEPARTMENT OF ENVIRONMENTAL CONSERVATION

AIR QUALITY CONTROL CONSTRUCTION PERMIT

Permit No.: 231CP03

Proposed – October 27, 2004

Rescinds and Replaces Permit No. 231CP02

The Department of Environmental Conservation (department), under the authority of AS 46.14 and 18 AAC 50, issues Air Quality Control Construction Permit No. 231CP03 to:

Owner and Operator: **Trident Seafoods Corporation (Trident)**
5303 Shilshole Avenue, NW
Seattle, WA 98107-4000
(206) 783-3818

Permittee: **Same as Owner and Operator**

Stationary Source **Akutan Seafood Processing Facility (Akutan)**

Location: Latitude 54° 08' 00" North; Longitude 165° 47' 00" West
UTM Zone 3 - 448,591 m East; 5,998,283 m North

Physical Address: Akutan Harbor
P.O. Box 9
Akutan, Alaska 99553

Permit Contact: Earl R. Hubbard (206) 783-3818

The department authorizes Trident to modify the stationary source in accordance with the original permit application, subsequent submittals listed in Section 3, and the terms and conditions of this permit. As required by AS 46.14.120(c), the Permittee shall comply with the terms and conditions of this construction permit.

This permit satisfies the obligation of the owner and operator to obtain a construction permit as set out in AS 46.14.130(a).

The construction permit classification of Akutan is 18 AAC 50.300(b)(1)(A). The modification is classified under 18 AAC 50.300(h)(2). The owner requested limit revision is classified under 18 AAC 50.305(a)(3) and (4).

John F. Kuterbach
Manager, Air Permits Program

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Abbreviations/Acronyms

AAC	Alaska Administrative Code
ADEC	Alaska Department of Environmental Conservation
AS	Alaska Statutes
ASTM	American Society of Testing and Materials
CEMS	Continuous Emission Monitoring System
C.F.R.	Code of Federal Regulations
COMS	Continuous Opacity Monitoring System
EMS	Environmental Management System
EPA	US Environmental Protection Agency
FITR	Fuel Injection Timing Retard
HHV	Higher heating value
MACT	Maximum Achievable Control Technology
NA	Not Applicable
NAICS	North American Industry Classification System
NESHAPS	Federal National Emission Standards for Hazardous Air Pollutants [as defined in 40 C.F.R. 61]
NSPS	Federal New Source Performance Standards [as defined in 40 C.F.R. 60]
PS	Performance specification
PSD	Prevention of Significant Deterioration
RM	Reference Method
SCR	Selective Catalytic Reduction
SIC	Standard Industrial Classification
SN	Serial Number
TBD	To Be Determined

Units and Measures

bhp	brake horsepower or boiler horsepower ¹
gr./dscf	grains per dry standard cubic foot (1 pound = 7,000 grains)
dscf	Dry standard cubic foot
GPH	gallons per hour
kW	kilowatts
kW-e	kilowatts electric ²
MMBtu	Million British Thermal Units
ppm	Parts per million
ppmv	Parts per million by volume
TPH	Tons per hour
TPY	Tons per year
Wt%	weight percent

Pollutants

CO	Carbon Monoxide
HAPS	Hazardous Air Pollutants [as defined in AS 46.14.990(14)]
H ₂ S	Hydrogen Sulfide
NO _x	Oxides of Nitrogen
NO ₂	Nitrogen Dioxide
NO	Nitric Oxide
PM-10	Particulate Matter [as defined in 18 AAC 50.990(70)]
SO ₂	Sulfur Dioxide
VOC	Volatile Organic Compound [as defined in 18 AAC 50.990(103)]

¹ For boilers: One boiler horsepower = 33,472 Btu-fuel per horsepower-hour divided by the boiler's efficiency.
For engines: approximately 7,000 Btu-fuel per brake horsepower-hour is required for an average diesel internal combustion engine.

² kW-e refers to rated generator electrical output rather than engine output

Section 1 Authorizations

1. **Source Inventory.** The Permittee is authorized to operate at Akutan the units listed in Table 1.¹

Table 1 – Source Inventory^a

ID	Source Name	Source Description	Rating/size	Install Date
1	Pollock Generator #4	Caterpillar (Cat) Model D3516B Low NO _x Diesel Electric Generator, Serial Number (SN) 7RN00229	1,655 kW-e	5/1/94
2	Cod Generator #1	Cat Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00273	1,135 kW-e	1/24/98
3	Cod Generator #2	Cat Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00274	1,135 kW-e	1/24/98
4b	Pollock Generator #1	Cat Model D3516B Quad Turbo Low NO _x Diesel Electric Generator, SN 7RN01420	1,655 kW-e	12/03
5	Pollock Generator #2	Cat Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00514	1,135 kW-e	6/15/00
6	Pollock Generator #3	Cat Model D3512B Twin Turbo Low NO _x Diesel Electric Generator, SN 8EM00253	1,240 kW-e	11/1/99
7a	Cod Generator #3	Cat Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 1GZ01229	1,135 kW-e	11/03
8	Pollock Boiler #1	Cleaver Brooks Model NCB 100-400 Steam Boiler, SN 85166	16.74 MMBtu/hr	1/15/90
9	Pollock Boiler #2	Cleaver Brooks Model NCB 100-400 Steam Boiler, SN 85165	16.74 MMBtu/hr	1/15/90
10	Cod Boiler #1	Johnston 516 AC Steam Boiler, SN 4756	5.11 MMBtu/hr	5/1/82
11	Cod Boiler #2	Johnston 516 AC Steam Boiler, SN 4757	5.11 MMBtu/hr	5/1/82
12	Fish Meal Drier	Pedar Halvorsen Furnace, SN#502511	7.67 MMBtu/hr	7/96
23	Boiler	Cleaver Brooks Model 189-500 Steam Boiler, SN L52745	21 MMBtu/hr	10/96
24	Boiler	Falcon Boiler, SN M8616	1.02 MMBtu/hr	6/95
25	Sealand Engine	Detroit Diesel Series 60 Diesel Electric Generator, SN 06R0096733	350 kW-e	9/95
26	Compressor Engine	Cat Model 3508B Twin Compressor Engine, SN 6PN00401	2.69 MMBtu/hr	1/24/98
27 ^b	Freshwater Pump House Generator	Cat Model D3512A, Diesel Electric Generator, SN 24Z01359	1,135 kW-e	4/96
28 ^b	Cod Generator #4	Cat Model D379, Diesel Electric Generator, SN 34Z00770	420 kW-e	6/82
29 ^b	Cod Generator #5	Cat Model D379, Diesel Electric Generator, SN 34Z00771	420 kW-e	6/82
30 ^g	Trash Incinerator	Therm Tec Model G-50, SN 7916	750 lb trash/hr	2/02
T1	Tank #1	Fish Oil	49,750 gallons	1991
T2	Tank #2	Diesel	372,320 gallons	1988
T3	Tank #3	Diesel	372,320 gallons	1988
T4	Tank #4	Diesel	372,320 gallons	1988
T5	Tank #5	Diesel	372,320 gallons	1988
T6	Tank #6	Diesel	216,000 gallons	1982

Table Notes:

^a Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

^b Authorized by consent decree dated December 12, 2002

¹ This table corrects and updates the source inventory at Akutan **prior to** this construction permit.

2. **Modification Authorization.** The Permittee is authorized by this construction permit to upgrade or replace Emission Units 2, 3, 5, 6, 7a, 28, and 29 with 2a, 3a, 5a, 6a, 7b, 28a, and 29a respectively, as described in Table 2 and in accordance with condition 14.5. The Permittee shall notify the department's Fairbanks office in writing seven days prior to initial start-up of each new or modified emission unit identifying the unit number, serial number, anticipated initial startup date, installation date, and removal date of replaced unit, if applicable. Prior to installation of a new unit, the Permittee shall remove the old unit.

Table 2 – Modification Authorizations^a

ID	Source Name	Source Description	Rating/size	Install Date
2a	Cod Generator #1	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00273	1,360 kW-e	1/24/98 Mod TBD
3a	Cod Generator #2	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00274	1,360 kW-e	1/24/98 Mod TBD
5a	Pollock Generator #2	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8RM00514	1,360 kW-e	6/15/00 Mod TBD
6a	Pollock Generator #3	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 8EM00253	1,240 kW-e	11/1/99 Mod TBD
7b	Cod Generator #3	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator, SN 1GZ01229	1,360 kW-e	11/03 Mod TBD
28a	Cod Generator #4	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator, SN n/a	1,655 kW-e	TBD
29a	Cod Generator #5	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator, SN n/a	1,655 kW-e	TBD

Table Notes:

^a Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

3. **Engine Installation Authorization.** The Permittee is authorized to install Emission Units 25a, 31, 32, 33, and 34 as described in Table 3 and in accordance with condition 14.5. The Permittee shall notify the department's Fairbanks office in writing seven days prior to initial start up of each new or modified emission unit, identifying the unit number, serial number, anticipated initial start-up date, installation date, and removal date of replaced unit, if applicable. Prior to installation of Unit 25a, the Permittee shall remove Unit 25.

Table 3 – Engine Installation Authorizations^a

ID	Source Name	Source Description	Rating/size	Install Date
25a	Portable Generator #1	'Portable' Detroit Diesel Series 60 Diesel Electric Generator	350 kW-e	TBD
31	Portable Generator #2	'Portable' Detroit Diesel Series 60 Diesel Electric Generator	350 kW-e	TBD
32	Portable Generator #3	'Portable' Detroit Diesel Series 60 Diesel Electric Generator	350 kW-e	TBD
33	Cod Generator #6	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator, SN n/a	1,655 kW-e	TBD
34	Cod Generator #7	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator, SN n/a	1,655 kW-e	TBD

Table Notes:

^a Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

4. **Selective Catalytic Reduction (SCR) Installation Authorization.** The Permittee is authorized to install and operate SCR units listed in Table 4 as needed. The Permittee is authorized to install additional SCR units at their discretion.

Table 4 – SCR Installation Authorizations^a

ID	SCR ID	Source Name	Source Description	Install Date
1	A	167249/32	SINOX System 2000	12/02
4b	B	167580/105	SINOX System 2000	6/03
2, 2a	C	167580/106	SINOX System 2000	6/03
5, 5a	D	167370/17	SINOX System 2000	9/04
3, 3a	E	167370/15	SINOX System 2000	9/04
	F	167370/12	SINOX System 2000	10/04

Table Notes:

^a Except as noted elsewhere in this permit, the information in this table is for identification purposes only.

5. **Used Oil Authorization.¹** The Permittee may burn a fuel oil/used oil blend or a fuel oil/fish oil/used oil blend in heaters and boilers as follows:
- 5.1 Comply with fuel sulfur requirements in condition 14.
- 5.2 Comply with the state PM standard as follows:
- Measure the ash content of each batch of used oil, prior to blending with any other fuel. If greater than 0.89 percent by weight, report to the department in accordance with the excess emission reporting requirement listed in Section 10 of Operating Permit No. 231TVP01 Revision 2.
 - Blend the used oil with fuel oil (or fuel oil/fish oil blend) using a metering system or other reproducible method accurate to plus or minus two percent at a ratio of one gallon of used oil to at least five gallons of fuel oil (or fuel oil/fuel blend). Record the date, the quantity of used oil blended (gallons), and the quantity of fuel oil (or fuel oil/fish oil) blended (gallons).
- 5.3 Include in the operating report required in Section 10 of Operating Permit No. 231TVP01 Revision 2, the information required under condition 5.2b for the reporting period.
6. **Fish Oil Engine Authorization.** The Permittee may burn blended fuel oil/fish oil blends in each engine emission unit upon department approval. Monitor, record, and report as follows:
- 6.1 Comply with fuel sulfur requirements in condition 14.
- 6.2 Comply with NO_x PSD avoidance limits in condition 8 as follows:
- Conduct NO_x emission source testing using procedures set out in Section 9 of Permit 231TVP01, Revision 2 within ten operating days after initial conversion to blended fish oil/fuel oil, and as follows to obtain department approval, except as set ou in condition 6.3.

¹ CAUTION! Although this condition should ensure compliance with the applicable emission standards of 18 AAC 50, this permit does NOT ensure compliance with other applicable state or federal laws concerning management, use, or disposal of used oil.

- (i) Test each unit at no less than three loads (high, mid, and low) within the normal operating range of the unit. If the Permittee proves that units have identical configuration, the department will allow one unit to be tested within that group.
 - (ii) During each test, monitor and record opacity in accordance with Sections 13 and 14 of Operating Permit No. 231TVP01, Revision 2.
 - (iii) At each load, test at the desired fish oil/fuel oil blend(s) and at 100 percent diesel fuel.
 - (iv) During each test, monitor and record the unit's average load, electric generation rate, and blended fuel consumption rate.
 - (v) Determine the fuel-specific higher heating value (gross heat value) for each fuel or fuel blend used during the testing, by obtaining a vendor certification or by analyzing a representative sample of the fuel or blend in accordance with ASTM D 240, 4809 or 2382.
 - (vi) Determine load-specific NO_x emission factors (pounds per gallon and pound per hour) expressed as NO₂, based on Method 19.
 - (vii) Include the information obtained in conditions 6.2a(ii) through 6.2a(vi) in the source test report required in Section 9 of Operating Permit No. 231TVP01, Revision 2.
 - b. After department approval, if source test results show different engine-specific and fuel-specific NO_x emission factors for blended fuels than that demonstrated for fuel oil, use the blended fuel oil/fish oil emission factors to calculate the unit's 12 consecutive month total emissions in condition 8 during any period during which the unit combusts blended fuel oil/fish oil retroactive to date of test.
- 6.3 Obtain department approval in writing before using fish oil blend in any emission unit equipped with SCR.
- a. Obtain from the vendor a demonstration that the fish oil/fuel oil blend will not cause or contribute to an accelerated decrease of engine and SCR performance.
 - b. Submit to the department:
 - (i) the SCR vendor demonstration that include compatibility of SCR reagent and fish oil;
 - (ii) the estimated emission reduction compared to diesel fuel;
 - (iii) the recommended changes of dosing and concentration of reagent in SCR (remapped to engine if needed); and
 - (iv) the recommended increase in SCR maintenance and inspection intervals.
 - c. If the department approves the use of fish oil blend, comply with the requirements of conditions 6.1 and 6.2.

- 6.4 Blend the fish oil with fuel oil using a metering system or other reproducible method accurate to plus or minus five percent. Blend at a ratio not to exceed that for which Trident has conducted emission source tests under condition 6.2a to verify site-specific NO_x emission factors.
- a. Record the date, volume of fish oil (gallons), volume of fuel oil (gallons) in the blend, and the blend ratio.
 - b. Report as excess emissions according to Section 10 of Operating Permit No. 231TVP01 Revision 2, if the blend ratio exceeds the ratio for which Trident has conducted emission source tests under condition 6.2a.
 - c. Include in the operating report required in Section 10 of Operating Permit No. 231TVP01 Revision 2, the information required under condition 6.4a for the reporting period.

Section 2 *Permit Terms and Conditions*

7. Environmental Management System.

- 7.1 Operate Akutan in accordance with air quality control provisions of the department-approved Environmental Management System (EMS).
- 7.2 Update the EMS to include management of new and revised air quality control obligations as set out in this construction permit within 60 days after the operating permit is revised to incorporate terms and conditions of this construction permit.

Owner Requested Limits to Avoid Stationary Source Classification as PSD-Major

- 8. **Limit to Avoid Classification as PSD-Major for NO_x.** The Permittee shall limit Akutan's NO_x emissions to no more than 240 tons in any twelve consecutive months. Trident may use aqueous urea-based Selective Catalytic Reduction (SCR) as described in condition 9 to actively reduce NO_x emissions in addition to operational restrictions. Monitor, record, and report as follows:

- 8.1 **Fuel Consumption (Fuel Oil, Fish Oil, and Used Oil) and Operating Hour Monitoring.** Install and operate a dedicated continuous monitoring system for recording fuel consumption that is accurate to within two percent on each of Units 1 through 12, and 23 through 34, including replacement units, listed in Table 1, Table 2, and Table 3.
 - a. Monitor and record monthly and SCR interval fuel consumption (*TC* and *CC*) in gallons for each unit (SCR interval as defined in condition 9.3).
 - b. Monitor and record monthly and SCR interval operating hours for each unit (SCR interval as defined in condition 9.3).
 - c. For any period during which the fuel consumption monitoring system is out-of-bounds or not operational, then for purposes of calculating NO_x emission in condition 8.3, determine the monthly or SCR interval fuel consumption based on the hours recorded in condition 8.1b, and the design fuel consumption rate in Exhibit A.
- 8.2 **Engine Load Requirements.**
 - a. Limit Unit 26 to loads no greater than 79 percent by limiting the the monthly fuel consumption rate to 62.6 gallons per hour. Calculate and record monthly fuel consumption rate by dividing the total fuel consumed in the month by the total hours of operation for the month.
 - b. For all engines not equipped with SCR, calculate and record monthly percent load by dividing the monthly fuel consumption (gallons) by the hours operated in the month, then dividing that number by the design fuel consumption rate in gallons per hour from Exhibit A, and multiplying by 100.

- c. For engines equipped with SCR
- (i) Calculate and record the SCR interval percent load by dividing the SCR interval fuel consumption (gallons) by the hours operated during the interval, then dividing that number by the design fuel consumption rate in gallons per hour from Exhibit A, and multiplying by 100 (SCR interval as defined in condition 9.3).
 - (ii) Calculate and record percent load for the remainder of the month by dividing the monthly uncontrolled fuel consumption (gallons) by the hours operated in the month without SCR, then dividing that number by the design fuel consumption rate in gallons per hour from Exhibit A, and multiplying by 100.
- 8.3 By the 15th of each month, calculate the the previous months monthly total NO_x emissions as follows:
- a. **Engines.**
- (i) For each engine that **did not** use SCR for any part of the month, calculate and record the monthly NO_x emissions using Equation 1; as an alternative, for any specific engine, use the PTE for the engine listed in Exhibit A as monthly NO_x emissions.

Equation 1 $NO_x = TC \times EF \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

Where:

NO_x	=	NO _x emissions in tons per month;
TC	=	Fuel consumption in gallons per month for each unit that did not use SCR during the month (measured or calculated in accordance with condition 8.1a); and
EF	=	NO _x uncontrolled emission factor from Exhibit A, based on the monthly average load recorded under condition 8.2b for each unit, except as indicated in condition 6.2b for fish oil combustion.

- (ii) For each engine that **did** use SCR for any part of the month, calculate and record emissions using conditions 8.3a(ii)(A) and 8.3a(ii)(B); as an alternative, for any specific engine, use the PTE for the engine listed in Exhibit A as monthly NO_x emissions.

- (A) Calculate the monthly NO_x emissions **while using SCR**, for each interval using Equation 2.

$$\text{Equation 2} \quad NO_x = \left[\sum_{i=1}^n (eff_i \times CC_i) \times EF_i \right] \times \frac{1 \text{ ton}}{2000 \text{ lb}}$$

Where:

NO_x	=	NO _x emissions in tons per month;
n	=	Number of intervals during the month for which a given engine used SCR
CC	=	Controlled fuel consumption in gallons for each interval i (measured or calculated in accordance with condition 8.1a);
eff	=	The SCR effectiveness for interval i (measured or calculated in accordance with condition 9.3)
EF	=	NO _x uncontrolled emission factor from Exhibit A based on the load recorded under condition 8.2c(i) for interval I , except as indicated in condition 6.2b for fish oil combustion.

- (B) Calculate the monthly NO_x emissions **while not using SCR** using Equation 3.

$$\text{Equation 3} \quad NO_x = UC \times EF \times \frac{1 \text{ ton}}{2000 \text{ lb}}$$

Where:

NO_x	=	NO _x emissions in tons per month;
UC	=	Uncontrolled fuel consumption in gallons for each engine ($UC = TC - (CC1 + CC2, \text{ etc})$, TC and CC measured or calculated in accordance with condition 8.1a);
EF	=	NO _x uncontrolled emission factor from Exhibit A based on the load recorded under condition 8.2c(ii) for each unit, except as indicated in condition 6.2b for fish oil combustion.

- Equation 4** $NO_x = TC \times EF \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

- c. **Incinerator** Charge no greater than 146 tons of refuse each month (equivalent to 400 lb/hour continuous capacity). Monitor, record, and report as follows:
 - (i) Weigh and record weight of each batch of waste charged in the incinerator. Calculate and record the total quantity of waste burned each month in tons.
 - (ii) Calculate and record actual NO_x emissions from the incinerator using Equation 5; as an alternative, use a PTE of 1.4 tpm for the incinerator.

Equation 5
$$NO_x = (TC \times 0.2) + (TW \times 2.6) \times \frac{1 \text{ ton}}{2000 \text{ lb}}$$

Where:

NO_X	=	NO _X emissions in tons per month for Unit 30;
TC	=	Fuel consumption in gallons per month (measured or calculated in accordance with condition 8.1a);
0.2	=	diesel fuel combustion emission factor (lb/gallon);
TW	=	monthly waste incinerated (tons); and
2.6	=	waste combustion emission factor (lb/ton)

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- 8.5 If the NO_x emissions calculated under condition 8.4 exceed 235 tons per 12 consecutive months, conduct a NO_x emission source test on each internal combustion engine, except for Units 25, 25a, 31, and 32 (the portable and backup units), within 90 days, unless a source test has been conducted within the previous 12 months. Conduct the tests at three loads within the normal operating range of the emission unit using procedures set out in Section 9 of Operating Permit No. 231TVP01, Revision 2, and as follows.
- a. For units equipped with SCR, simultaneously conduct the test upstream and downstream of the SCR unit.
 - (i) For each run, conduct a simultaneous instrument accuracy verification test using the Engine Exhaust NO_x Analyzer described in condition 10 to collect one representative sample. Obtain readings from directly upstream and directly downstream of the SCR according to regular operational procedures in conditions 10.2, 10.3b, and the QA/QC Plan in item 30 of the consent decree dated December 5, 2002.
 - (ii) For each test, determine the load curve, the urea reagent concentration, the urea flow rate, and the ammonia slip.
 - b. During each test, monitor and record the unit's average load, electric generation rate, and fuel consumption rate.
 - c. For each test, analyze a representative fuel sample to determine its higher heating value and specific gravity using ASTM methods incorporated by reference in ASTM 396-62, Specifications for Fuel Oil.
 - d. Determine the load-specific NO_x emission rate (pounds per gallon and pounds per hour), based on Method 19.
 - e. Include the information obtained in conditions 8.5a through 8.5d in the source test report required in Section 9 of Operating Permit No. 231TVP01, Revision 2.
- 8.6 After department approval of the source tests conducted under condition 8.5, use the source test emission factors to calculate the unit's emissions in condition 8.3. If the emission factor in pounds per gallon for any given load differs from the values listed in Table A, recalculate 12 consecutive month total emission, starting six months prior to the source test, and submit an updated operating report for those periods as needed.
- 8.7 Report as excess emissions under Section 10 of Operating Permit No. 231TVP01, Revision 2 any time the NO_x emissions calculated under condition 8.4 or 8.6 exceeds 240 per 12 consecutive months.
- 8.8 Include in the operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2:
- a. monthly total fuel use and operating hours for each unit, under condition 8.1a or 8.1c;
 - b. engine loads (monthly average, SCR interval) recorded conditions 8.2;

- c. monthly total waste incinerated recorded under condition 8.3c(ii); and
 - d. monthly and 12 consecutive month total NO_x emissions for the stationary source under condition 8.4 or 8.6.
9. **Selective Catalytic Reduction (SCR) Requirements.** For each SCR system, install and operate SCR units in accordance with the department-approved Quality Assurance/Quality Control Plan (QA/QC) Plan developed under item 30 of the consent decree dated December 5, 2002, as modified, and as follows.
- 9.1 Maintain on-site a spare catalyst bed in new condition for each group of compatible SCR units, except if the spare catalyst bed is compatible with all SCR units, the Permittee may maintain on-site only one catalyst bed in new condition for all units.
 - 9.2 Maintain on-site necessary vendor-recommended spare parts (spray nozzles, lance, pumps, seals, and solenoids).
 - 9.3 **SCR NO_x Removal Effectiveness.** Determine SCR effectiveness for each interval¹ of SCR use as follows.
 - a. Measure total parts per million (ppm) nitrogen oxide (NO) concentration of exhaust stream before and after SCR treatment using a gas analyzer that meets the performance specifications set out in condition 10. Calculate nitrogen dioxide (NO₂) concentration of exhaust stream both before and after the SCR unit as five percent of the total NO_x in the exhaust stream as shown in Equation 6. Calculate the total NO_x of exhaust stream both before and after the SCR unit by summing the measured NO concentration and the calculated NO₂ concentration as shown in Equation 7. Calculate the effectiveness using Equation 8, upon initiating a period of SCR controlled operations for a specific engine; and, except as indicated in condition 9.3b, at least every seven operating days for the duration of continuous SCR emission controls of that engine.

Equation 6 $NO_2 = NO \left(\frac{0.05}{0.95} \right)$

Equation 7 $NO_x = NO + NO_2$

Equation 8 $eff = \frac{NO_x(in) - NO_x(out)}{NO_x(in)} \times 100$

Where:

- eff = SCR effectiveness in percent
- NO_{xin} = NO_x concentration in ppm before SCR
- NO_{xout} = NO_x concentration in ppm after SCR

¹ An SCR interval is any period between SCR Effectiveness tests, while the unit is using SCR.

- b. If the NO_x emissions calculated under condition 8.4 exceed 230 tons per 12 consecutive months, measure SCR effectiveness daily starting on the 15th of the month following the month that resulted in greater than 230 tpy NO_x emissions, and continuing until the 12 consecutive month NO_x emissions are shown to be below 230 tons per 12 consecutive months.
- c. Record the effectiveness for each SCR interval. (The effectiveness for each interval is the **lowest** effectiveness measured for the tests that bound that interval. (For instance, interval 1 is bounded by 80 percent and 85 percent. The effectiveness for interval 1, *eff1*, is 80 percent.)

9.4 **SCR Ammonia Slip.** The Permittee shall monitor, record, and report the concentration of ammonia (NH₃) in the exhaust gas (ammonia slip) of each unit equipped with SCR as follows.

- a. Measure the ammonia slip downstream of the SCR unit during SCR operations, once each day that SCR operates using a length of stain detection tube (Draeger Tube) calibrated for ammonia concentrations up to 25 ppmv.
- b. Record the date, time, method of measurement, and measured concentration.
- c. If the measured ammonia slip is above 10 ppm NH₃, contact the SCR vendor or certified technician and implement their prescribed corrective actions, and record:
 - (i) a complete description of the corrective action;
 - (ii) the date the corrective action was completed;
 - (iii) the technician's contact information (if the corrective action was prescribed by an SCR manufacturer or certified technician); and
 - (iv) if applicable, a description of how any corrective actions completed differed from what was prescribed by the SCR manufacturer or certified technician, and the basis for the difference.

9.5 Keep records of

- a. all SCR system repairs, maintenance, and SCR control system adjustments, including time and date;
- b. the dates and times each time that SCR controls are started up and shut down. Start-up means that the catalyst bed temperature is within the manufacturer's recommended temperature set points for optimal NO_x removal and reagent injection is at a rate consistent with the programable logic controller setting for the operating engine's load setting. Shut down means that the engine is no longer running or one of the above parameters is out of bounds;
- c. hourly records of SCR reagent concentration in lb/gal, and rate of reagent injection in gal/hr;
- d. receipts for all urea purchases (with dates and quantities);
- e. system alarm logs including time, date of occurrence; and

- f. date and time of every effectiveness test conducted under condition 9.3, and results.
- 9.6 Include in the operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2, all records required under condition 9, except for the records required under condition 9.5c. Maintain the records required under condition 9.5c on-site for five years from the date of the record.
- 10. **Engine Exhaust NO_x Analyzer.** The Permittee shall maintain two (primary and secondary) exhaust gas NO_x analyzers onsite that are capable of measuring nitric oxide (NO) concentrations of one to 1,000 ppmv and that is accurate to five ppmv in accordance with the QA/QC Plan developed under item 30 of consent decree dated December 5, 2002, as modified. Comply with the following for analyzers required under this condition.
 - 10.1 Install on the stacks of units capable of operating with SCR:
 - a. sampling ports that comport with 40 C.F.R. 60, Appendix A, Method 1, Section 2.1, and a stack or duct free of cyclonic flow at the port location during the applicable test methods and procedures;
 - b. safe sampling platforms;
 - c. safe access to sampling platforms; and
 - d. utilities for emission sampling and testing equipment.
 - 10.2 Develop an analyzer exhaust traverse for each sampling port of no less than three points to ensure representative sampling.
 - 10.3 Relative Accuracy Requirements.
 - a. Keep calibration gas available onsite at all times.
 - b. Before each test SCR effectiveness test required by condition 9.3, test the analyzer's relative accuracy using NO_x calibration gas as follows:
 - (i) Measure and record the:
 - (A) date;
 - (B) certified NO_x concentration of the calibration gas (*NO_x certified*); and
 - (C) measured NO_x concentration of the calibration gas (*NO_x measured*).
 - (ii) Calculate and record the relative accuracy using Equation 9.

Equation 9
$$RA = \frac{NO_{x\text{certified}} - NO_{x\text{measured}}}{NO_{x\text{certified}}}$$

Where: RA = Relative Accuracy

- c. Recalibrate or repair the primary analyzer if relative accuracy exceeds five percent, and no less than once each year. The recalibration must be performed by the manufacturer or a trained technician.

- d. Keep records of each relative accuracy test. Notify the department within seven days of the audit date if any analyzer's relative accuracy calculation conducted under condition 10.3b results in a relative accuracy greater than five percent.
 - e. Include with the operating report required by Operating Permit 231TVP01, Revision 2:
 - (i) a copy of the receipt for any recalibration following return of the recalibrated analyzer required under condition 10.3c; and
 - (ii) a copy of any records and notifications required under condition 10.3d.
- 10.4 When the primary analyzer requires recalibrations or repairs under condition 10.3c, use the secondary analyzer for all measurements required under this permit. Follow all requirements listed in condition 10.3.
11. **Limit to Avoid Classification as PSD-Major for SO₂.** The Permittee shall limit Akutan's SO₂ emissions to less than 250 tons in any 12 consecutive months. Monitor, record, and report as follows.
- 11.1 By the 15th of each month, calculate the previous months monthly total SO₂ emissions for each unit as follows.
- a. Except as indicated in condition 11.1b, calculate and record the monthly SO₂ emissions using Equation 10.

Equation 10 $SO_2 = TC \times EF \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

Where:

SO_2	=	SO ₂ emissions in tons per month;
TC	=	Fuel consumption in gallons per month for each unit (measured or calculated in accordance with condition 8.1a); and
EF	=	SO ₂ emission factor in pounds per gallon, using an appropriate emission factor based on fuel sulfur content, as required under condition 14.

- b. Except as indicated in condition 11.1c, for any specific unit, the Permittee may use the PTE for the unit listed in Exhibit B as monthly SO₂ emissions.
 - c. The Permittee may recalculate the PTE for each unit listed in Exhibit B using an alternate fuel sulfur content allowed under condition 14, and use the recalculated PTE as monthly SO₂ emissions for a given unit.
- 11.2 Add the monthly SO₂ emission for all units calculated under condition 11.1 to obtain the stationary source monthly total. Add the monthly stationary source total to the stationary source total for the previous 11 months to determine the 12 consecutive month total for the stationary source.

- 11.3 Report as excess emissions under Section 10 of Operating Permit No. 231TVP01, Revision 2 if the SO₂ emissions calculated under condition 11.2 exceed 249 tpy.
- 11.4 Include in the operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2 monthly and 12-consecutive month total NO_x emissions for the stationary source under condition 11.2.

Ambient Air Quality Requirements

12. **General Ambient Air Quality Provisions.**

- 12.1 Build and maintain the source as proposed in the March 2004 application. If the application is inconsistent with terms of this permit, then comply with the permit requirements.
- 12.2 **Public Access Control Plan.** The Permittee shall comply with the provisions of the Public Access Control Plan contained in the application dated March 2004, with the ambient air quality boundary as revised in application supplements submitted to the department June 9, 2004¹ and June 14, 2004.²
 - a. The ambient air boundary shall be completely within the Lease Boundary established with each surface owner of lands and waters within the revised ambient air boundary.
 - b. Do not decrease the size of the controlled area without department approval. For department approval, submit proposed changes to the ambient air boundary, along with a revised ambient air impact analysis for those areas that will become ambient air, to the department's Air Permits Program.
 - c. Do not revise the Public Access Control Plan without department approval. Submit revisions to the Public Access Control Plan to the department's compliance assurance group for written approval prior to implementing changes to the plan.
- 13. **NO₂ Ambient Air Quality Protection.** The Permittee shall protect the NO₂ ambient air quality standard and increment as follows:
 - 13.1 Comply with the NO_x limit in condition 8.
 - 13.2 Comply with the general provisions in condition 12.
 - 13.3 Comply with the exhaust stack provisions in conditions 14.4 and 14.5.
- 14. **SO₂ Ambient Air Quality Protection.** The Permittee shall protect the SO standard and increment as follows:
 - 14.1 Comply with the general provisions in condition 12.
 - 14.2 Upon permit issuance, limit fuel sulfur to 0.35 wt% S for all units except the incinerator.

¹ Email from Tom Gibbons (Steigers) to Sally A Ryan (department).

² Email from Tom Gibbons to Sally A. Ryan.

14.3 For the incinerator, limit fuel sulfur to 0.50 wt% S.

14.4 Within 30 days of permit issuance, extend and maintain the stack heights of all stacks for currently permitted units to, at a minimum, the stack height in Table 5.

Table 5 – Minimum Required Stack Heights Upon Permit Issuance or Upon Unit Startup (meters above grade)¹

Unit	Stack Height
1	20.6
2, 2a	21.5
3, 3a	21.5
4, 4a, 4b	20.6
5, 5a	20.6
6, 6a	20.6
7, 7a, 7b	21.5
8	27.5
9	27.5
10	21.5
11	21.5
12	27.5
23	19.0

Unit	Stack Height
24	11.2
25	7.6
26	20.6
27	6.00
28	7.02
28a	21.6
29	7.02
29a	21.6
30	8.31
31	7.6
32	7.6
33	21.6
34	21.6

14.5 If the Permittee installs additional engines 28a, 29a, 33, and 34, the Permittee shall install them consecutively in the order 28a, 29a, 33, then 34, and as described in 14.5a, 14.5b, 14.5c, and 14.5d, respectively. In addition to the notifications required under conditions 2 and 3, notify the department's Fairbanks office in writing within 15 days after installation of Units 28a, 29a, 33, and 34. In the notification, for conditions 14.5b, 14.5c, and 14.5d, indicate which subcondition Trident will use to comply with ambient air quality standards listed under the condition.

a. Upon installation of Unit 28a:

- (i) remove Unit 28;
- (ii) limit fuel sulfur of condition 14.2 to 0.32 wt% S for all units except the incinerator; and
- (iii) extend and maintain the stack heights to the heights listed in Table 5.

b. Upon installation of Unit 29a, remove Unit 29, and comply with **either** condition 14.5b(i) or 14.5b(ii).

- (i) Limit fuel sulfur of condition 14.2 to 0.29 wt% S for all units except incinerator, and extend and maintain stack heights to the heights listed in Table 5.
- (ii) Limit fuel sulfur of condition 14.2 to 0.30 wt% S for all units except incinerator; and extend and maintain the extended stack heights to the heights listed in Table 5, **except** extend and maintain the stack of:
 - (A) Units 28a and 29a to 27.6 meters above grade; and

¹ Use these stack heights unless required to extend stack height in condition 14.5.

- (B) Unit 23 to 25.1 meters above grade.
- c. Upon installation of Unit 33, comply with **either** condition 14.5c(i) or 14.5c(ii).
- (i) Limit fuel sulfur of condition 14.2 to 0.27 wt% S for all units except incinerator, and extend and maintain stack heights to the heights listed in Table 5.
- (ii) Limit fuel sulfur of condition 14.2 to 0.28 wt% S for all units except incinerator, and extend and maintain the extended stack heights to the heights listed in Table 5, **except** extend and maintain the stack of:
- (A) Units 28a, 29a, and 33 to 27.6 meters above grade; and
- (B) Unit 23 to 25.1 meters above grade.
- d. Upon installation of Unit 34, comply with **either** condition 14.5d(i) or 14.5d(ii).
- (i) Limit fuel sulfur of condition 14.2 to 0.24 wt% S for all units except incinerator, and extend and maintain stack heights to the heights listed in Table 5.
- (ii) Limit fuel sulfur of condition 14.2 to 0.26 wt% S for all units except incinerator, and extend and maintain the extended stack heights to the heights listed in Table 5, **except** extend and maintain the stack of
- (A) Units 28a, 29a, 33, and 34 to 27.6 meters above grade; and
- (B) Unit 23 to 25.1 meters above grade.
- e. Install emission sampling ports and safe emission test sampling platform consistent with 40 C.F.R. 60.8(e) and Appendix Method 1 or 1A, and condition 10 for each stationary diesel internal combustion engine.

14.6 Limit unit operation as follows:

- a. Do not concurrently operate Units 10 and 11.
- b. Do not operate Unit 24 unless Unit 8, 9 or 23 is shut-down.
- c. Do not operate any secondary unit (Units 27 through 29) unless a comparable (like or larger sized) primary unit listed in Table 6 is not operating for each operating secondary unit.

Table 6 – Comparable Primary Units

Secondary Unit	Comparable Primary Units
27, 28, 29	1 – 7, 26, 28a, 29a, 33 and 34

14.7 Monitor fuel sulfur as follows:

- a. Obtain a statement or receipt from the fuel supplier certifying the maximum sulfur content of the fuel for each shipment of fuel delivered to the Plant. If a certified statement or receipt is not available from the supplier, analyze a representative sample of any fuel added to any tank at the plant in accordance with condition 14.7b.
- b. If required under this permit to determine the sulfur content of fuel oil, used oil, or fish oil, use ASTM method D129-00, D1266-98, D1552-95, D2622-98, D4294-98, D4045-99, D-4294 or an alternative method approved by the department.
- c. Except as indicated in condition 14.7d, calculate and record the sulfur content, by weight, of the fuel in each tank (Tanks 1 through 6), after each time fuel is added to a tank, using Equation 11.

Equation 11
$$S_T = \frac{(Q_{F1} \times S_{F1}) + (Q_{F2} \times S_{F2}) + (Q_{F3} \times S_{F3})}{100}$$

Where:

Q_{F1}	=	Quantity of Fuel 1 (delivered fuel), percent of total fuel, by weight
S_{F1}	=	Sulfur content of Fuel 1, percent sulfur by weight
Q_{F2}	=	Quantity of Fuel 2 (fuel in tank before delivery), percent of total fuel, by weight
S_{F2}	=	Sulfur content of Fuel 2, percent sulfur by weight
Q_{F3}	=	Quantity of Fuel 3 (lower sulfur fuel as needed to meet applicable sulfur limit), percent of total fuel, by weight
S_{F3}	=	Sulfur content of Fuel 3, percent sulfur by weight
S_T	=	Sulfur content of blended fuel in the tank, percent sulfur by weight

- d. If the sulfur content of any diesel fuel delivery is less than the applicable limit specified in condition 14 (based on selected operating scenario), then Trident may elect to assume the fuel in all tanks to which that fuel is added is the same as the maximum of any fuel added to that tank in the previous 12 months, and may forego fuel sulfur calculations in condition 14.7c.
- e. Keep records of statements or receipts from the fuel supplier showing sulfur content and quantity of each shipment of fuel under condition 14.7a, results of each sulfur measurement required under condition 14.7b, and each fuel sulfur calculation for each tank conducted under condition 14.7c.
- f. Report as excess emissions in accordance with Section 10, Operating Permit No. 231TVP01, Revision 2 whenever the fuel with a sulfur content that exceeds the applicable limit in condition 14 is consumed at the Plant.

- g. Include the information required under condition 14.7e in the operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2.

14.8 Monitor stack height as follows:

- a. Provide as-built drawings and photographs of the modified/installed stacks and their emission sampling port locations:
 - (i) for Units 10, 11 and 25 within 60 days of permit issuance;
 - (ii) for Unit 23, within 60 days of increasing height, if required; and
 - (iii) for Units 28a, 29a, 31, 32, 33 and 34, within 60 days of installation of the given new or replacement unit.
- b. Include a summary of the notifications provided in conditions 2, 3, and 14.8a with the operating report required by Operating Permit No. 231TVP01, Revision 2 for the time of notice.

14.9 When each secondary unit listed in condition 14.6c is started up:

- a. record the unit identification number, date, and time of startup and shutdown; and
- b. record the unit identification number of the equivalent or larger sized replaced primary unit removed from operation prior to the secondary unit startup time, and tag that primary unit as out of service until the date and time the secondary unit has shut down.

14.10 Report as excess emissions under Section 10 of Operating Permit No. 231TVP01, Revision 2, any time a secondary unit is operated without an equivalent or larger sized primary unit out-of-service.

14.11 Include the records required under condition 14.9 with the operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2.

15. **PM-10 Ambient Air Quality Protection.** The Permittee shall protect the PM-10 ambient air quality standards and increments as follows:

- 15.1 Comply with the general provisions in conditions 12, and 5.2.
- 15.2 Comply with the exhaust stack provisions in conditions 14.4 and 14.5.
- 15.3 Comply with the concurrent operation provisions in condition 14.6.

State Emission Standards for Fuel Burning Equipment

16. **Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding water vapor, emitted from the emission units authorized by this construction permit (Units 1, 2, 2a, 3a, 4b, 5, 5a, 6, 6a, 7a, 7b, 27, 28, 28a, 29, 29a, 31 through 34 listed in Table 1 through Table 3) to reduce visibility through the exhaust effluent by any of the following:

- a. more than 20 percent for greater than three minutes in any one hour;
- b. more than 20 percent averaged over any six consecutive minutes.

- 16.1 Verify compliance using either condition 16.1a or 16.1b, using each fuel or fuel blend¹ for each unit.
- Prior to unit installation, obtain a certified manufacturer guarantee that each emission unit will comply with the visible emission standard and attach a copy of the guarantee to the operating report required for the installation period under Section 10 of Operating Permit No. 231TVP01, Revision 2.
 - Conduct a visible emission observation in accordance with Sections 13 and 14 of Operating Permit No. 231TVP01, Revision 2 within 90 days after initial start-up or after permit issuance for existing units authorized by this permit. Attach a copy of the surveillance records to the operating report required for that time under Section 9 Operating Permit No. 231TVP01, Revision 2.
- 16.2 Monitor, record, and report according to Sections 13 and 14 of Operating Permit No. 231TVP01, Revision 2.
17. **Particulate Matter.** The permittee shall not cause or allow PM emissions from emission units authorized by this construction permit (1, 2, 2a, 3a, 4b, 5, 5a, 6, 6a, 7a, 7b, 27, 28, 28a, 29, 29A, 31 through 34 listed in Table 1 through Table 3) to exceed 0.05 grains per cubic foot corrected to standard conditions and averaged over three hours using all allowable fuels for each unit. Monitor, record, and report according to Sections 13 and 14 of Operating Permit No. 231TVP01, Revision 2.
18. **Sulfur Compound Emissions.** The permittee shall not cause or allow sulfur compound emissions, expressed as SO₂, from emission units authorized by this construction permit (1, 2, 2a, 3a, 4b, 5, 5a, 6, 6a, 7a, 7b, 27, 28, 28a, 29, 29a, 30, 31 through 34 listed in Table 1 through Table 3) to exceed 500 ppm corrected to standard conditions and averaged over three hours. Monitor and record, according to the fuel sulfur requirements of condition 14.7.

State Emission Standards for Incinerators

19. **Incinerator Visible Emissions.** The Permittee shall not cause or allow visible emissions, excluding condensed water vapor, through the exhaust of Emission Unit 30, to reduce visibility by any of the following:
- more than 20 percent for greater than three minutes in any one hour;²
 - more than 20 percent averaged over any six consecutive minutes.
- 19.2 Verify compliance using either condition 19.2a or 19.2b.
- Prior to source installation, obtain a certified manufacturer guarantee that each emission unit will comply with the visible emission standard and attach a copy of the guarantee to next operating report required under Section 10 of Operating Permit No. 231TVP01, Revision 2.

¹ Including used oil or fish oil blends.

² This requirement is in the EPA-approved State Implementation Plan (SIP) for the state of Alaska. Although state regulations no longer include this requirement as of May 3, 2002, it is federally enforceable until EPA adopts the new state regulations into the SIP.

- b. Conduct a visible emission source test within 90 days after permit issuance and attach a copy of the surveillance records to the next operating report required under Section 10 Operating Permit No. 231TVP01, Revision 2.

19.3 Monitor, record, and report according to Sections 13 and 14 of Operating Permit No. 231TVP01, Revision 2.

Federal New Source Performance Standards (NSPS) Requirements

- 20. For Unit 30, keep records on a calendar quarter basis of the weight of municipal solid waste burned (or other EPA approved method), and the weight of all other fuels and wastes burned in the unit.

Section 3 *Permit Documentation*

December 20, 2002	Operating Permit No. 231TVP01, Revision 2
December 5, 2002	Consent Decree between Trident and the department, regarding Akutan
May 2, 2003	Operating and Construction Permit Application for Trident Akutan.
July 31, 2003	Operating and Construction Permit Application, Revision 1 for Trident Akutan.
December 5, 2003	Construction Permit 231CP02 for Trident Akutan
December 26, 2003	Application Supplement – correction to summary tables for source tests conducted in October 2003.
March 2004	Operating and Construction Permit Application, Revision 2. Supercedes all previous applications.
June 3, 2004	Email from Tom Gibbons (Steigers) to Sally Ryan (ADEC) containing excerpts from May 2002 source test report (not certified as true, accurate and complete).
June 9, 2004	Email from Tom Gibbons (Steigers) to Sally Ryan (ADEC) containing supplemental application information (not certified as true, accurate and complete).
June 14, 2004	Email from Tom Gibbons (Steigers) to Sally Ryan (ADEC) containing supplemental application information (not certified as true, accurate and complete).
June 18, 2004	Email from Tom Gibbons (Steigers) to Jim Baumgartner (ADEC) regarding incinerator VOC emissions (not certified as true, accurate and complete).
June 21, 2004	Email from Tom Gibbons (Steigers) to Sally Ryan (ADEC) regarding Akutan Harbor vessel information (not certified as true, accurate and complete).
June 22, 2004	Email from Tom Gibbons (Steigers) to Jim Baumgartner (ADEC) regarding Caterpillar D3516B Generator Engine Rating (certified as true, accurate and complete on July 7, 2004).
September 13, 2004	Email from John Steigers (Steigers) to Jeanette Brena (ADEC) regarding new SCR installations.
October 8, 2004	Email from Earl Hubbard (Trident) to Jeanette Brena (ADEC) and Alan Schuler (ADEC) regarding the Akutan Construction Permit.

EXHIBITS

Exhibit A – Uncontrolled NO_x Emission Factors and Monthly Potential to Emit^a

Unit	Source Description	Uncontrolled NO _x Emission Factor (EF) (lb/gal), based on percent load							Design Fuel Consumption @ 100% load (gph)	NO _x PTE (tpm)
		≤50	51 – 70	70	71 - 84	85	86 - 99	100		
1, 4b, 28a, 29a, 33, 34	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator (1,655 kW)	0.233	0.236	0.236	0.246	0.246	0.246	0.239	118.6	10.3
2, 3, 5, 7a	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,135 kW)	0.352	0.352	0.317	0.317	0.269	0.278	0.278	78.3	7.9
2a, 3a, 5b, 7b	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,360 kW)	0.242	0.242	0.209	0.209	0.204	0.208	0.208	98.9	7.5
6a	Caterpillar Model D3512B Twin Turbo Low NO _x Diesel Electric Generator (1,240 kW)	0.155	0.176	0.176	0.200	0.200	0.219	0.220	85.8	6.9
6b	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,240 kW)	0.252	0.252	0.217	0.217	0.205	0.205	0.203	88.4	6.5
8, 9	Cleaver Brooks Model 400 Steam Boiler	n/a	n/a	n/a	n/a	n/a	n/a	0.0200	122.2	0.9
10, 11	Johnston Steam Boiler	n/a	n/a	n/a	n/a	n/a	n/a	0.0200	37.3	0.3
12	Pedar Halvorsen Furnace	n/a	n/a	n/a	n/a	n/a	n/a	0.0200	252.6	1.8
23	Cleaver Brooks Model 500 Steam Boiler	n/a	n/a	n/a	n/a	n/a	n/a	0.0200	153.3	1.1
24	Falcon Boiler	n/a	n/a	n/a	n/a	n/a	n/a	0.0200	7.4	0.1
25, 31, 32	Portable Detroit Diesel Series 60 Diesel Electric Generator	n/a	n/a	n/a	n/a	n/a	n/a	0.400	18.7	27
26	Caterpillar Model D3508B Twin Compressor Engine	0.203	0.203	0.203	0.203	n/a	n/a	n/a	62.6 (79%)	4.6
27	Caterpillar D3512A	0.335	0.373	0.373	0.373	0.356	0.356	0.305	85.7	9.5
28, 29	Caterpillar D379	n/a	n/a	n/a	n/a	n/a	n/a	0.222	31.0	2.5

Table Notes

^a NO_x Emission Factors and PTE may change upon department approval of source tests.

Exhibit B – SO₂ Emission Factors and Monthly Potential to Emit

Unit	Source Description	Design Fuel Con. @ 100% load (gph)	SO ₂ Potential to Emit (tons/month), based on 0.35 wt% S fuel sulfur content ^a
1, 4b, 28a, 29a, 33, 34	Caterpillar Model D3516B Quad Turbo Low NO _x Diesel Electric Generator (1,655 kW)	118.6	2.2
2, 3, 5, 7a	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,135 kW)	98.9	1.4
2a, 3a, 5a, 7b	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,360 kW)	98.9	1.6
6	Caterpillar Model D3512B Twin Turbo Low NO _x Diesel Electric Generator (1,240 kW)	85.8	1.6
6a	Caterpillar Model D3512B Quad Turbo Low NO _x Diesel Electric Generator (1,240 kW)	88.4	1.6
08, 09	Cleaver Brooks Model 400 Steam Boiler	122.2	0.6
10, 11	Johnston Steam Boiler	37.3	1.8
12	Pedar Halvorsen Furnace	252.6	1.1
23	Cleaver Brooks Model 500 Steam Boiler	153.3	2.2
24	Falcon Boiler	7.4	0.7
25, 31, 32	Portable Detroit Diesel Series 60 Diesel Electric Generator	18.7	4.6
26	Caterpillar Model D3508B Twin Compressor Engine	62.6 (79%)	2.8
27	Caterpillar D3512A	85.7	0.1
28, 29	Caterpillar D379	31.0	0.3

Table Notes

^a SO₂ PTE will change if fuel sulfur content is different than 0.35 wt% S.